

BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH

In the Matter of the Application of)	Docket No. 07-035-93
Rocky Mountain Power for Authority to)	
Increase Its Retail Electric Service Rate in)	Surrebuttal Testimony of
Utah and for Approval of Its Proposed)	Randall J. Falkenberg
Electric Service Schedules and Electric)	On Behalf of the
Service Regulations, Consisting of a)	Utah Committee of
General Rate Increase of Approximately)	Consumer Services
\$161.2 Million Per Year, and for Approval)	
Of a New Large Load Surcharge)	

May 23, 2008

REDACTED

Redacted Confidential Material is highlighted in gray.

SURREBUTTAL TESTIMONY OF RANDALL J. FALKENBERG

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.

A. Randall J. Falkenberg, PMB 362, 8351 Roswell Road, Atlanta, Georgia 30350. I am the same Randall J. Falkenberg who pre-filed direct testimony in this docket on April 7, 2008 and rebuttal testimony on May 9, 2008.

Q. PLEASE SUMMARIZE YOUR SURREBUTTAL TESTIMONY.

A. My surrebuttal testimony makes the following points. All figures are on a Utah basis:

1. The Company's comparisons of my GRID results to actual cost are incorrect and misleading. The Commission should give them no weight.
2. Mr. Duval's criticism of my workpapers is unfair because the Company failed to file timely data requests. The Committee expedited its response to the Company's request for workpapers and offered to explain them to the Company.
3. I continue to support my commitment logic adjustments and non-firm transmission recommendation.
4. My proposed planned outage schedule is the most reasonable alternative in this case. I demonstrate it produces results nearly identical to a composite of four GRID studies using the Company's actual planned outage schedules from the four-year period.
5. I continue to support my heat rate modeling and minimum loading deration adjustments.
6. I continue to support elimination of the monthly outage rates, and demonstrate why the Commission to reject Mr. Duval's new proposal to eliminate the weekday-weekend outage rate split.
7. I reduce the Ramping Adjustment (CCS 4.19) by \$636 thousand, using actual ramp rates to establish the ramping included in the EFOR.
8. I show that Mr. Duval's characterization of certain CCS and DPU adjustments as "updates" or "new information" is a misleading attempt to justify inclusion of

- new costs and a selective update of data favorable to the Company. I recommend these adjustments be made without the forward curve update.
9. Because the Commission invited the Company to update its filing at the time of the test year change, it should reject Mr. Duval's proposed inclusion of new costs and the forward curve adjustment. If the Commission allows the forward curve update, I recommend it also require the Company to reshape the hydro energy in GRID to reflect the new forward curve.
10. I correct an error in the Call Option (CCS 4.5) adjustment, decreasing NPC by approximately \$457 thousand.
11. I withdraw the STF Arbitrage and Trading Profits (CCS 4.13) adjustment.
12. I continue to support the Committee's SMUD re-pricing and normalization adjustments.
13. I withdraw the Proper Hydro Weighting Adjustment (CCS 4.15) and instead recommend the Commission require the Company to file a complete 40 water year simulation in its next general rate case.
14. I withdraw the Bridger Outages (CCS 4.18) and Station Service in Heat Rates (CCS 4.24) adjustments.
15. I make a correction of \$102 thousand reducing the Self Supply Owned Reserve (CCS 4.26) adjustment.
16. I reduce the Wind Integration adjustment by \$188 thousand.
17. I accept the DPU Adjustment 6.3 related to the Kennecott and Tesoro contracts.
18. In summary, my revised NPC recommendation is \$1,002 million total Company resulting in a reduction to the Company's originally filed request of \$48.7 million. Total recommended adjustments reduce Utah allocated NPC by \$20.5 million.

Revisions to NPC Recommendations

Q. HAVE YOU REVISED AND UPDATED YOUR RECOMMENDATIONS PRESENTED IN TABLE 1 OF YOUR DIRECT TESTIMONY?

A. Yes. In light of the Company's rebuttal, I have made a number of revisions and changes to the recommendations I made in my direct testimony. The table below shows the changes from my direct testimony.

**Table 1 Surrebuttal
Adjustments and Corrections to Table 1**

			Total Company	Est. Utah Jurisdiction
				SE 41.70%
				SG 42.48%
I. GRID (Net Variable Power Cost Issues)				
1 PacifiCorp Request NPC - GND-15			1,050,698,899	
CCS Direct Case Adjustments to NPC			(59,450,639)	(25,023,369)
CCS GRID Result Direct Case			991,248,260	
Revisions to Direct Case				
CCS4.5	Reverse	Call Options - Direct	2,502,690	1,053,407
CCS4.5S	Include	Call Options - Surrebuttal (Correction)	(3,587,460)	(1,509,998)
CCS4.13	Reverse	STF Arbitrage and Trading Profits	3,584,812	1,508,883
CCS4.15	Reverse	Proper Hydro Weighting	3,471,982	1,461,392
CCS4.18	Reverse	Bridger Error Outages	1,249,330	525,855
CCS4.19	Reverse	Ramping	3,981,680	1,675,929
CCS4.19S	Include	Maximum Ramping - Surrebuttal	(2,471,712)	(1,040,368)
CCS4.24	Reverse	Station Service in Heat Rate Curve	1,523,178	641,121
CCS4.25	Reverse	Wind Integration Charges - Direct	1,690,147	711,400
CCS4.25S	Include	Wind Integration Charges - Surrebuttal	(1,242,997)	(523,190)
CCS4.26	Reverse	Remove Self Supply Non-Owned Reserve - Direct	2,186,441	920,295
CCS4.26S	Include	Remove Self Supply Non-Owned Reserve - Surrebuttal	(1,945,285)	(818,790)
DPU6.3	Include	Kennecott and Tessoro Adjustments	(225,498)	(94,914)
Total Revisions			10,717,308	4,511,022
CCS Surrebuttal Case Adjustments to NPC			(48,733,331)	(20,512,346)
CCS GRID Result Surrebuttal Case			1,001,965,568	

Comparison to Actual Costs

Q. DO YOU HAVE ANY COMMENTS CONCERNING MR. DUVAL'S TESTIMONY COMPARING YOUR RECOMMENDED TEST YEAR NET POWER COSTS TO THE COMPANY'S MOST RECENT ACTUAL NET POWER COST RESULTS?

A. Yes, I have several comments. First, while he is ostensibly criticizing my testimony, in reality, I believe Mr. Duval is re-arguing the Commission's decision to use the 2008 test year. The disparity between recent actual costs and GRID model results has much more to do with the many differences that exist between the Commission's 2008 test year and the circumstances that occurred during the historical period, than it has to do with the adjustments that I recommended be made to the Company's GRID modeling. The fact that Mr. Duval made no

95 attempt to examine the differences between the 2008 test year and the historical
96 period he cites, is unfortunately, quite misleading.

97 Second, the suggestion that unaudited and unadjusted actual cost provides
98 a reasonable benchmark for ratemaking purposes is highly debatable. The use of
99 actual costs has come up in Utah and in other states as well in the past, but hasn't
100 been applied in Utah for many years. Nor has the Company consistently
101 advocated use of actual cost. The Company apparently perceives a benefit (in
102 terms of reduced regulatory lag) from the use of projected test years rather than
103 historical actual costs and supported changes to legislation that enabled the
104 expanded use of projected test years. It should not be now allowed to select the
105 higher of historical actual or projected normalized.

106 Third, it is important to recognize that if actual costs are to be used, they
107 would still need to be audited and normalized for ratemaking purposes. Use of
108 "normalized actual" costs would not be an endeavor free of controversy. There
109 are many differences in the system between recent historical periods and the rate
110 effective period. There would be substantial disputes concerning not only the
111 normalization of actual costs, but also the prudence of those costs. Mr. Duval's
112 suggestion that the Commission should now place reliance on the most recent 12
113 months of actual costs (which has never been subjected to audit and which clearly
114 fails to reflect numerous known differences between the historical period and the
115 rate effective period) is little more than an attempt to "change the subject" (if not
116 the test year) from the relevant issues in this case, to something else the Company
117 would rather focus on.

118 This should not detract the Commission from the real issues of this case.
119 Much of the recent increase in actual power costs has been due to higher than
120 expected load growth. Mr. Duval makes little mention of this fact. The main
121 problem resulting in higher than expected power costs lies with the Company's
122 own load forecast (which I used), not my GRID model results, or prior
123 Commission decisions. However, if the Company were to increase its sales
124 forecast in GRID, it would also have to increase its revenue forecast, billing units,
125 and jurisdictional allocations factors. All of this has been ignored by Mr. Duval.

126 Fourth, Mr. Duval's apparent suggestion (based on GND-2R-RR) that
127 because the Company believes it has undercollected net power costs in the past
128 (2001-2007), it should be now given a more sympathetic ear by the Commission
129 in this case is also specious. The Company has not challenged whether past rates
130 were just and reasonable. Thus, this argument has no merit. The Commission
131 must set rates in this case based on evidence presented in this case, not reconsider
132 prior (mostly settled) cases.

133 Finally, this is not the first time the Company has tried to "change the
134 subject" by making dubious comparisons between test year normalized and recent
135 actual power cost results. In the 2001 rate case, Mr. Duval's predecessor, Mr.
136 Widmer, also presented a "last minute" appeal to actual NPC results in his
137 rebuttal testimony, which he contended showed that criticisms to the Company's
138 study were unfounded:

139 "During 2000 the Company experienced significantly higher purchased
140 power prices as a result of the western energy crisis. As a result, 2000
141 actual net power costs were approximately \$833 million on a Total

Company basis compared to the Company's current proposed net power costs of \$806 million, or almost double the amount included in rates.

Q. Does the Company expect net power costs to decline substantially from these levels during 2001?

A. No. Actual net power costs for the first four months of 2001 totaled \$372 million. On an annual basis, the Company's 2001 net power costs were forecasted to be approximately \$760 million on a Total Company basis in a February 2001 forecast. However, it should be noted that FERC recently placed a cap on wholesale energy prices that has resulted in much lower market prices today and through the remainder of the year, based on current expectations. Unfortunately, the Company's previously executed forward purchases are now higher priced than the current forward price curve. *This has effectively eliminated the prior expected benefits of the Company's forward purchases, which had the effect of driving the lower expected net power costs for the second half of 2001, referred to by Mr. Falkenberg on page 10 of his testimony. As a result, the Company now expects net power costs to be substantially higher than the \$760 million previously forecast.* (Docket No. 01-035-01, Rebuttal Testimony of Mark Widmer, page 5.)

The Commission's final order did not rely on that analysis in the 2001 case. Instead the Commission concentrated on the actual issues at hand, selecting a NPC result that provided its best evaluation of the conditions appropriate to the test period, even though the final result was less than the recent actual cost results.¹

Q. ON PAGE 7 OF HIS TESTIMONY, MR. DUVAL SAYS IT WAS UNREASONABLE FOR YOU TO RECOMMEND A NET POWER COST RESULT FOR THE 2008 TEST YEAR THAT IS \$38 MILLION LESS THAN THE ACTUAL NPC FOR THE MOST RECENT 12 MONTH. IS HIS CONTENTION VALID?

A. No. The \$38 million disparity he cites results largely from my use of the test year approved by the Commission, the Company's GRID model and its load forecast. As far as the comparison to actual cost, I'd point out that the result I presented in

¹ Mr. Widmer's comparisons failed to include the Hunter outage, which accounted for a large portion of the differences, and much like Mr. Duval's presentation was highly misleading.

177 direct testimony, \$991 million, exceeds PacifiCorp's actual 2007 NPC by
178 approximately \$16 million. My adjustments are appropriate corrections to
179 problems with the Company's modeling. Further, I have now increased my
180 recommended NPC result, by more than \$10 million.

181 **Q. PLEASE DISCUSS MR. DUVAL'S COMPARISON TO ACTUAL**
182 **RESULTS FOR THE 12 MONTHS ENDED MARCH 31, 2008.**

183
184 A. There are many reasons why these recent actual net power costs are much
185 different from the 2008 test year GRID results. Table 2 below attempts to capture
186 the most important differences between my 2008 GRID test year, and the
187 Company's twelve month ending March 31, 2008 actual results. It shows the
188 changes in energy in both load and resources between the test year that I used and
189 Mr. Duval's historical period. To make our figures comparable, substantial
190 changes to either actual costs, or GRID results would be needed. My estimate of
191 these required cost changes applied to my GRID study are shown in the table as
192 well. Naturally, it is difficult to quantify these impacts, but the figures below
193 represent acceptable estimates.

194

F

Surrebuttal Table 2

	Actual 3.31.2008	GRID 12.31.2008	Difference	Cost Impact
Load Change	59,072,835	58,505,214	-567,621	59,873,043
Hydro Difference	5,714,924	6,410,990	696,066	34,230,110
LakeSide	1,959,810	2,889,432	929,622	33,033,258
TransAlta	845,664	0	-845,664	-14,147,988
SMUD Contract	465,671	350,400	-115,271	9,448,580
Blundell	165,673	272,753	107,080	4,722,211
Wind Generation	700,427	1,062,885	362,458	20,841,329
Gas Prices	N/A	N/A	N/A	-45,741,145
Coal Prices (Negligible)	N/A	N/A	N/A	N/A
			Total	102,259,399
		RJF Final Result		991,248,260
		Adjusted Result		1,093,507,659

First, the 2008 test year modeled in GRID reflects lower loads than actually occurred in the 12 month ended March 31, 2008 period. In fact, based on the figures shown in GND 3R-RR, there was 567,621 more mWh for the 12 months ended March 31, 2008 as compared to the calendar year 2008 test year. I could not rerun GRID using the higher load numbers because I did not have the hourly load data. However, Mr. Duval already provided an estimate of the change in GRID power costs resulting from a change in loads in GND-5R-RR. Applying his results would support an increase in NPC of almost \$60 million in my projected GRID result. It should be fairly clear that my GRID results would be much higher had I used the actual loads for the recent historical period. Mr. Duval makes no mention of this fact. It should be pointed out, that I simply used

218 the test year loads prepared by the Company for its 2008 test year. I made no
219 changes to the native customer load data used in GRID.

220 **Q. IS THIS THE ONLY DIFFERENCE BETWEEN ACTUAL RESULTS AND**
221 **YOUR GRID STUDY?**

222
223 A. No. I'm sure Mr. Duval realizes that the Lake Side plant came on-line several
224 months late. Lake Side did not begin full operation until September 8, 2007.
225 Thus, the 12 months ended March 31, 2008 NPC report used by Mr. Duval, would
226 include the plant for only about half of the period. My study, of course, assumed
227 Lake Side would be online for the entire period. If I had only used six months of
228 Lake Side production, my study results would have been \$33 million higher.
229 Again, this significant difference between actual results and my GRID study has
230 nothing to do with any adjustments I proposed.

231 **Q. DOES THE LAKE SIDE IN SERVICE DATE ISSUE ALSO ILLUSTRATE**
232 **OTHER MATTERS CONCERNING THE USE OF ACTUAL COST?**

233
234 A. Yes. Were the Commission to rely solely on actual costs it should find out why
235 the Lake Side unit did not come on line in time for the summer 2007 peak period.
236 Were the Commission to rely solely on actual costs (as in a PCA) it should find
237 out why the Lake Side unit did not come on line in time for the summer 2007
238 peak period and remove any imprudent costs resulting from higher purchased
239 power costs that were required. However, Utah uses normalized rather than
240 actual costs. If "normalized actual costs" were being used, then the Commission
241 should remove the \$33 million in higher replacement power costs resulting from
242 the delay of Lake Side.

243 **Q. WHAT OTHER DIFFERENCES EXIST BETWEEN MARCH 2008**
244 **ACTUALS AND YOUR GRID STUDY?**

245
246 A. Based on the actual power cost reports, hydro generation was below the GRID
247 normalized hydro forecast for 2008. The 2008 GRID study I used has nearly 700
248 thousand more mWh of hydro generation than the actual results for the twelve
249 months ended March 31, 2008. While I did propose a minor adjustment to hydro
250 modeling, it changed the overall hydro generation by a very little. Reflecting the
251 actual hydro conditions for the historical period would increase my NPC result by
252 an additional \$34 million. As with the other issues, I again, relied almost
253 exclusively on the Company's hydro inputs to GRID and the Commission's test
254 year.

255 Further, wind generation is increasing rapidly on the system. Wind
256 generation is expected to increase by more than 360 thousand mWh between the
257 12 months ended March 2008 period Mr. Duval used and the 2008 test year
258 approved by the Commission. Had I used the historical wind generation in my
259 GRID study, NPC would increase by an additional \$20 million. Also, generation
260 from the low cost Blundell geothermal plant is increasing in 2008 by more than
261 100 thousand mWh. Had I reflected lower generation for this plant in the test
262 year, NPC would have increased by \$5 million.

263 **Q. DID THE COMPANY ADJUST THE SMUD CONTRACT IN THE**
264 **ACTUAL NPC REPORTS TO MATCH THE RATEMAKING**
265 **TREATMENT USED BY THE COMMISSION?**
266

267 A. No. In the actual report for 2007 cited by Mr. Duval, the Company did not do so.
268 However, for ratemaking purposes, the Commission has historically used a
269 \$37/mWh revenue figure. Mr. Hayet proposed a price of \$43.2/mWh. Also, for
270 ratemaking purposes (such as in the Wyoming PCAM), the Company normally

271 imputes revenue to the SMUD provisional sales using a market price figure, while
272 they are normally excluded from GRID. Using the unadjusted actual data and
273 contract price for SMUD would increase NPC by \$9.5 million in my GRID study.

274 **Q. WHAT OTHER DIFFERENCES EXIST BETWEEN THE ACTUAL AND**
275 **TEST YEAR RESULTS?**

276
277 A. Gas prices have increased in the test year as compared to the historical period
278 used by Mr. Duval. Reflecting the lower historical gas prices would result in a
279 reduction to my GRID model results of \$45 million. Also, the TransAlta contract
280 was in place for the first three months of Mr. Duval's historical period. Including
281 TransAlta for a comparable period in my GRID study would result in a \$14
282 million reduction to NPC. Coal prices differed slightly between the two period,
283 but not enough to result in a substantial change to NPC.

284 If all of these adjustments were made to my proposed GRID model result,
285 the total NPC would be \$1,094 million, an amount that is substantially higher than
286 the test year result that I recommend.

287 **Q. WHAT INFERENCE SHOULD THE COMMISSION DRAW FROM THIS**
288 **COMPARISON OF ACTUAL TO GRID RESULTS?**

289
290 A. First of all, I believe the Commission would want to apply the 2008 test year
291 assumptions I used (discussed above) during the rate effective period. It is now
292 too late to change the load forecast. While the Company was invited to update its
293 test year when the Commission issued its test year order, Mr. Duval did not do so.
294 To reflect higher loads now would require changes to power cost model inputs,
295 billing units, revenues, and allocation factors.

296 Further, the other changes I used were built into the test year by the
297 Company and reflect current conditions. Lake Side has come on line, gas prices
298 are now higher, TransAlta is gone, hydro should return to normal levels, wind
299 generation is increasing and so on. The 2008 test year is clearly more reflective
300 of the rate effective period than the most recent 12 months of history. There is
301 simply no comparison between the two. Mr. Duval's suggestion to the contrary is
302 simply erroneous.

303 While Mr. Duval contends that I was unreasonable for recommending the
304 \$991 million figure, *the disparity with recent actual results stems largely from*
305 *differences that had nothing to do with the adjustments I am recommending in the*
306 *model.* Were I to conform my study to the major assumptions of the recent
307 historical periods, my results would be much, much higher. Indeed, even higher
308 than recent historical results. Load changes, provide by far the most significant
309 difference between actual and GRID model results. I simply used the load
310 forecast provided by the Company. If Mr. Duval has an argument with anyone,
311 perhaps he should address it to the Company's load forecast group.

312 While I am not suggesting that the above represents a complete
313 delineation of the differences between my GRID study, and Mr. Duval's actual
314 results, it does illustrate that the two are hardly comparable in any fair sense.
315 Given that this case has proceeded up until now, based on GRID model studies
316 using on a 2008 test year, I recommend the Commission ignore Mr. Duval's
317 attempted distraction and focus instead on the real issues of this case, *just as it did*

318 *in the 2001 proceeding when Mr. Widmer presented a similar comparison to*
319 *actual results in the rebuttal stage of the case.*

320 **Q. EXPLAIN FURTHER WHY CHANGES IN LOAD SHOULD NOT BE**
321 **CONSIDERED RELEVANT BY THE COMMISSION IN ITS**
322 **EVALUATION OF NPC.**

323
324 **A.** There is no other input to the ratemaking process that has a more profound effect
325 on the final rates established than load inputs. The Commission had the
326 opportunity to select a mid-2009 test year that contained higher loads than the
327 2008 test year, but it chose not to do so. Much of the difference between recent
328 history and the GRID results is due to the load inputs. For this reason, I believe
329 Mr. Duval's criticism of my study really amounts to a criticism of the
330 Commission's test year decision. The use of a later test year would have
331 increased NPC by roughly \$41 million. Given that the Committee did not oppose
332 the Company's original test year proposal, Mr. Duvall's criticism of my study
333 appears misplaced.

334 **Q. DO YOU HAVE ANY FURTHER COMMENTS CONCERNING EXHIBIT**
335 **GND-2R-RR?**

336
337 **A.** Yes. In this exhibit Mr. Duval attempts to show that the Company has historically
338 undercollected power costs in Utah. However, his exhibit is flawed because he
339 makes no effort to determine why the Company may have undercollected power
340 costs in the past. Again, I believe that rapid sales growth was an important
341 reason. A fair analysis of under collecting net power costs would also examine
342 whether any variance was due to imprudent decisions or planning by the
343 Company, or other factors such as the delay of the Lake Side plant.

344 **Q. CAN YOU ELABORATE ON THIS PROBLEM?**

345
346 A. Yes. Mr. Duval contends that the current NPC embedded in rates is \$813 million.
347 That figure is built into the 2007 and 2008 figures used in GND-2R-RR. The
348 \$813 million figure (based on sales projected for the 2006 rate case) assumed
349 21,538,272 mWh sales for Utah for the September 30, 2007 test year. The
350 Company's current case assumes 22,619,224 mWh Utah sales for the December
351 31, 2008 test year, an increase of 5%. As sales have increased, so have revenues
352 for recovery of net power costs. Reflecting the 5% sales increase increases the
353 current NPC in rates from \$813 to \$854 million, *some \$40 million more than*
354 *claimed by Mr. Duval.* Further, it appears that actual sales for the 12 months
355 ended March, 31, 2008 may have exceeded the Company's current test year
356 forecast.² As a result, Mr. Duval's comparisons of actual to NPC in rates are
357 wholly misleading and without value to the Commission.

358 **Q. WHAT IS THE CONCLUSION YOU DRAW FROM THIS?**

359
360 A. I urge the Commission to give no weight to the Company's arguments regarding
361 actual costs and alleged prior under-collections. Instead, I urge the Commission
362 to decide the NPC issues fairly, based on the merits of each adjustment.

363 **Workpapers and Support of CCS Adjustments**

364 **Q. MR. DUVAL CRITICIZED YOUR RESPONSE TO THE COMPANY'S**
365 **REQUEST FOR WORKPAPERS. PLEASE COMMENT.**

366
367 A. Mr. Duval testifies on page 24 as follows:
368
369 Despite a specific request for Mr. Falkenberg to produce organized, auditable
370 work papers, the Company received a huge electronic file from him without any
371 navigation instructions. Even though Mr. Falkenberg eventually produced a basic
372 map to his work papers, the Company was still unable to analyze Mr.
373 Falkenberg's adjustments in detail because of errors in his map and the difficulty

² This was certainly the case at the system level.

374 of locating the relevant files in the work papers among the many files that had
375 been created by Mr. Falkenberg that appear to have not been used to support any
376 of his adjustments.
377

378 **Q. IS THIS A FAIR COMMENT?**

379
380 A. No. Mr. Duval left out some very pertinent facts. First, the Company did not file
381 any data requests with the Committee to obtain my workpapers until April 21,
382 2008, two weeks after we filed our direct testimony. While the workpapers were
383 essentially complete by the filing deadline, we had no way of knowing what
384 specifically the Company might request. We received one minor data request
385 from the Company a week after we filed our direct testimony asking for some
386 backup information for a few of the Committee's adjustments. Responses were
387 provided on time to the Company. The Company has not yet objected to those
388 answers. On April 21, the Company filed a new data request specifically
389 requesting my workpapers. The Company also requested that the Committee
390 expedite the response. The response was expedited and by April 28th two CDs
391 with the workpapers were provided to the Company. The next day, the full
392 response was provided with basic "navigating instructions." Late in the day on
393 May 1st (the actual response due date) the Company requested that additional
394 detail concerning the "navigating instructions" be provided. I began working on
395 the request immediately. At the same time, the Committee offered to let the
396 Company talk to me to help sort out their difficulties. A more detailed set of
397 navigating instructions was provided by email before the close of business on
398 May 1, the original filing deadline for our response. By the following morning,
399 the Committee provided the Company with the 1st Supplemental response to the

400 Company's request 5.1, which was essentially the same information as produced
401 in the email, with a few minor revisions and corrections and provided more
402 detailed text explaining the information provided to the Company previously.

403 Based on discussions after Mr. Duval filed his rebuttal, the Company's
404 Manager of Net Power Costs appears to not have actually read the 1st
405 Supplemental Response as of May 16, 2008. If true, this would certainly explain
406 some of the difficulties in locating the specific GRID studies used to compute
407 individual adjustments.

408 Mr. Duval's statement that I "eventually" provided a "basic map" to the
409 workpapers leaves out the pertinent facts that the Company only filed its data
410 request long after the testimony was filed and the Committee provided the bulk of
411 the information three days earlier than requested by the Company. We also
412 offered to provide more detail to the Company by telephone if they desired. The
413 Company refused that offer.

414 **Q. PLEASE COMMENT ON MR. DUVAL'S CONTENTION THAT THE**
415 **COMPANY COULD NOT ANALYZE YOUR ADJUSTMENTS IN DETAIL**
416 **DUE TO THESE PROBLEMS.**

417
418 A. Having been on the other end of this type of issue many times over the years, I
419 can certainly sympathize a little with Mr. Duval's situation. However, in this
420 case, I think the problem stems from a lack of timely effort on the part of the
421 Company. The Company did not request workpapers in a timely fashion. Nor did
422 it read the all the pertinent information actually provided. Further, the Company
423 did not avail itself of the opportunity to ask questions informally via email or by
424 phone. I've worked with the Company for approximately ten years now. During

425 that time, there was always a free exchange of information outside of formal
426 discovery that worked both ways. In situations in which I did not receive
427 adequate responses to discovery requests, I submitted follow up discovery
428 requests seeking clarification of prior answers. In this case, I even scheduled on-
429 site interviews. In contrast, in this case the Company made no effort to resolve
430 any of its technical issues in this case by phone, email, face to face meeting, or
431 follow up discovery prior to the filing of Mr. Duval's testimony. If the Company
432 cannot understand the adjustments I proposed, it is due to a lack of effort on their
433 part. Considering that Mr. Duval has now agreed in full or in part to more than
434 half of the Committee's proposed adjustments, this seems to be little more than an
435 excuse or another attempted distraction.

436 **CCS 4.1 through CCS 4.4 (GRID Commitment Logic)**
437

438 **Q. DOES MR. DUVAL AGREE THAT THE GRID COMMITMENT LOGIC**
439 **IS FLAWED AND SHOULD BE CORRECTED BY NIGHT-TIME**
440 **SHUTDOWN SCREENS FOR THE COMBINED CYCLE PLANTS?**

441
442 **A.** Yes, though his testimony seems needlessly argumentative, he ultimately agrees
443 that GRID imprudently operates the system using its current logic. As such, he
444 proposes a night time shut down screen for the combined cycle units until the
445 GRID logic can be fixed. However, he provides no real justification for the
446 screens he proposes, nor any support for their use. Nor were there any
447 workpapers supporting these screens provided in any workpapers by the
448 Company. My assumption is the Company developed these inputs by "trial and
449 error" or based on the screens I provided in Exhibit CCS 4.6.

450 While I prefer the screens I developed, there is little difference between
451 the two. Our screens differ only in that I would have the Currant Creek night time
452 shut down screen start one hour earlier. Mr. Duval's proposed screen fails to
453 remove \$265 thousand of the uneconomic generation that I identified in the
454 model. Mr. Duval simply proposes that the Company be allowed to keep the cost
455 of this extra uneconomic generation. I disagree.

456 **Q. DISCUSS MR. DUVAL'S PROPOSED SCREEN FOR WEST VALLEY.**

457

458 **A.** Mr. Duval proposes a "light load hour screen" again with no support. This seems
459 unnecessary, as there is already a night time shut down screen for these units, and
460 it appears reasonable based on my studies. However, Mr. Duval would include
461 many days during the test year when GRID uneconomically commits West
462 Valley. This is questionable because the Company has agreed to remove
463 uneconomic generation costs from peaking units in prior cases in Oregon and
464 Wyoming. This was discussed in my direct testimony.

465 I continue to recommend the Commission require the Company to use
466 screens developed using the methodology described in my direct testimony. The
467 proposal I am making is superior to the Company's because it relies on an
468 analysis of daily costs during the test period that specifically addresses those
469 times when GRID is making incorrect decisions. While the impact of this change
470 is not large, Mr. Duval simply provides no basis for his proposal. Furthermore,
471 there is no justification to simply grant the Company the cost of uneconomic
472 generation that the Company would like to build into the model.

473 **Q. WHILE MR. DUVAL ACKNOWLEDGES THAT GRID IS IN ERROR,**
474 **AND APPEARS TO ACCEPT MOST OF YOUR PROPOSED**

475 **ADJUSTMENT, IS HIS PROPOSED CORRECTION ACTUALLY**
476 **INCLUDED IN THE COMPANY'S FINAL REBUTTAL NPC RESULT?**

477
478 A. No. Mr. Duval ultimately recommends Alternative 1 on GND-1RR. This NPC
479 result, 1,044 million is used in the Company's revised revenue requirement. That
480 figure does not include this correction, despite the fact that Mr. Duval clearly
481 acknowledges that GRID is wrong. Mr. Duval only conditionally accepts this and
482 several other equally valid corrections, if certain other, unrelated, changes to the
483 GRID inputs (such as a new forward price curve) are made. Mr. Duval's logic is
484 startling to say the least. He is suggesting that errors in the model should only be
485 corrected, if the Company is allowed to compensate by changing other unrelated
486 items to reflect cost updates. Absent that, Mr. Duval recommends the
487 Commission rely on costs he admits are based on incorrect input assumptions and
488 dispatch logic. I urge the Commission to reject this proposal by the Company. I
489 will discuss this matter as it pertains to other issues later in my testimony.

490 **Q. IN YOUR DIRECT TESTIMONY YOU PROPOSED THAT THE**
491 **COMPANY BE REQUIRED TO MODEL NON-FIRM TRANSMISSION IN**
492 **ITS NEXT GENERAL RATE CASE, PARTLY AS A MEANS OF**
493 **ADDRESSING THE PROBLEM OF UNECONOMIC GENERATION.**
494 **MR. DUVAL DISAGREES. PLEASE COMMENT.**

495
496 A. In late discovery I obtained some data related to non-firm transmission. As yet, I
497 have not fully developed a satisfactory method for reflecting non-firm
498 transmission in the test year. However, a few things are apparent already. First,
499 the impact of non-firm transmission is not large, but it is significant enough
500 (perhaps \$5 million on a total Company basis) that it should be included in GRID.
501 Second, non-firm transmission, by itself, is not a sufficient solution to the
502 problem of uneconomic generator commitment in GRID. There will still be a

503 need to solve the uneconomic generation problem in the future even if non-firm
504 transmission is used.

505 I disagree with Mr. Duval's suggestion that non-firm transmission be
506 ignored in the future. GRID should reflect an accurate forecast of prudent
507 operation of the system. Non-firm transmission is used by the system in order to
508 minimize costs. Just as it would be imprudent of the Company's real-time
509 personnel to ignore non-firm transmission, it would be imprudent to ignore it in
510 GRID, as well. Consequently, I continue to recommend the Commission require
511 the Company to file non-firm transmission data for the four-year period as part of
512 the MDRs in its next general rate case. This would not delay the filing, a concern
513 expressed by Mr. Duval.

514 **CCS 4.14 (Planned Outages)**

515

516 **Q. DOES MR. DUVAL ACKNOWLEDGE THAT THE COMPANY HAS**
517 **ASSUMED AN UNREALISTIC PLANNED OUTAGE SCHEDULE?**

518

519 A. Yes he does. Mr. Duval accepts the planned outage schedule of the DPU in
520 Exhibit GND-1R-RR- Alternative 1, and offers another schedule in Alternative 2.
521 It is unclear why he offers these two alternatives, but neither reflects proper
522 normalization. I have already addressed the problems with the DPU schedule in
523 my rebuttal testimony, so I won't restate all of those points here.³ However, Mr.
524 Duval made some additional arguments in favor of the two schedules he now
525 proposes.

526 **Q. WHAT ARE THE NEW ARGUMENTS MADE BY MR. DUVAL?**

527

528 A. Starting at line 379, Mr. Duval testifies as follows:

529 Mr. Falkenberg's proposed outage schedule does not take into consideration all of
530 the factors to be considered in outage planning. It is clear from page 54 of Mr.
531 Falkenberg's testimony that the primary criteria he used was to align the
532 maintenance schedule with the lowest market prices. As a result, his adjustment
533 lowered net power costs by more than twice the level of Mr. Dalton.
534

535 Mr. Duval's statement that the "primary criteria" I used was to align the
536 maintenance schedule with the lowest market prices is incorrect. The process I
537 used was to align the schedule with actual practice, considering the amount of
538 outage energy assigned to each month, the number of units on outage at a time,
539 and the amount of capacity on outage. However, in regard to Mr. Duval's
540 comment that attempts to make it appear that I did something wrong by aligning
541 the maintenance schedule with the lowest market prices, it turns out (based on our
542 on-site interviews and results from using actual schedules in GRID) that the
543 Company experts that actually schedule planned maintenance outages really do
544 attempt to minimize system costs to the extent possible (contrary to Mr. Duval's
545 assumptions.) This does entail "aligning the maintenance schedule with the
546 market prices." In other words, one should try to schedule planned maintenance
547 outages at a time that would result in the lowest costs to the system (which
548 typically occurs when market prices are lowest), so long as all maintenance
549 scheduling constraints are satisfied. I did just that.

550 Mr. Duval also contends the new outage schedule he has developed is
551 based on taking into account all of the factors discussed in CCS data request 6.15.
552 However, this is not much of a claim because, as I pointed out in my direct
553 testimony, the criteria discussed in CCS 6.15 were already applied in GRID, and

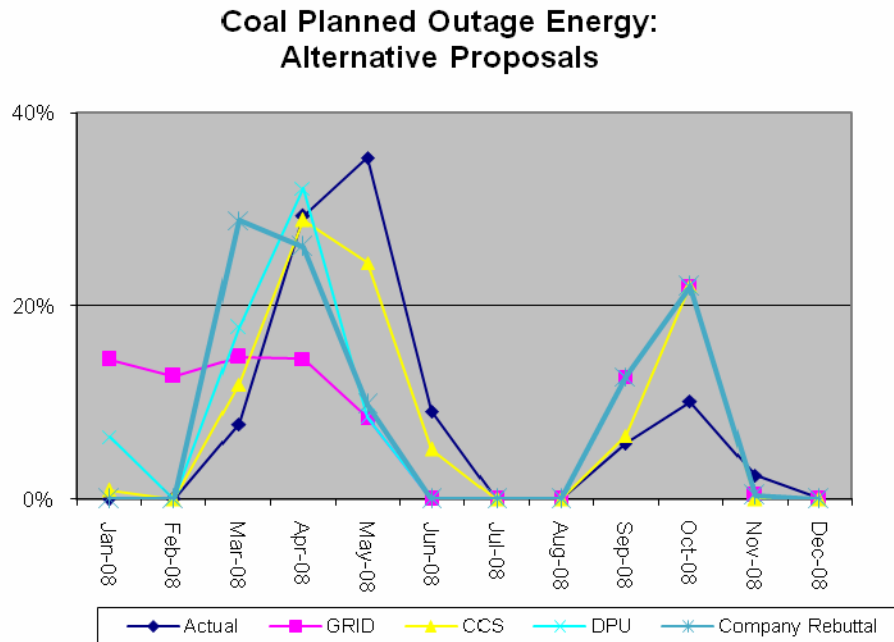
³ Note that while the Company now concedes its planned outage schedule is incorrect, it maintained

554 represented a far cry from the scheduling considerations actually used by the
555 Company.

556 **Q. CAN YOU PROVIDE A COMPARISON OF THE COMPETING OUTAGE**
557 **SCHEDULES IN THIS CASE?**

558
559 A. Yes. Figure 1, below compares the various schedules.⁴ As the figure shows, the
560 Company moved outages out of January and February, but most ended up in
561 March and April. Despite evidence of actual practice, the Company still proposes
562 to schedule no planned outage energy in June and very little in May. Historically,
563 May has the most planned outage energy. June is comparable to October, and
564 normally far exceeds September. It appears from Mr. Duvall's schedule, that his
565 primary criteria seems to have been to *avoid* scheduling maintenance in months
566 that have low market prices, which completely ignores the actual history during
567 the four-year period he used to establish the planned outage durations for each
568 resource.

⁴ in its response to CCS 5.1, that the schedule used in GRID was proper.
The line labeled "GRID" in the chart is based on the March filing for the test year.



569

570 **Q. IS THERE A WAY TO RESOLVE THIS ISSUE?**

571

572 A. I believe there is a very simple resolution to the matter. The Company bases its

573 normalized outage energy requirements on the most recent four years of historical

574 data (the 48 months ending June 2007) The simplest test of which outage

575 schedule (the DPU's, the Company's or mine) is most reasonable is to compare

576 the end results of each to the actual schedules used during the four-year period.

577 To do this I analyzed four distinct outage schedules for the one-year periods

578 starting September 1 for each year during the mid 2003 to mid 2007 period. By

579 comparing the costs of actual outages over the four-year period to the cost of the

580 various proposals made in this case we can determine which is most realistic.

581 Exhibit CCS 4.1SR provides the actual schedules I used.

582 **Q. ARE THERE OTHER ADVANTAGES TO THIS METHODOLOGY?**

583

584 A. Yes. The use of the actual schedules is not subjective as compared to

585 development of a schedule based on the GRID model criteria, or any other

method. The data is readily available from MDR 2.57-2 and easy to apply and interpret. The number of outage days and outage energy is the same for the normalized schedules and the actual four-year average. As the four-year average underlies the Company's planned outage requirements, this is a logical extension of the Company's methodology, which has been accepted by the Commission for many years. Finally, because all four of these schedules were actually used by the Company, there is no basis to suggest they were "result oriented" (i.e. solely designed to align with low market prices") impractical, infeasible or otherwise improper.

Q. WERE THERE ANY UNITS FOR WHICH THIS APPROACH COULD NOT BE APPLIED DIRECTLY?

A. Currant Creek and Lake Side were not online for the entire four-year period. The Company used both prior and projected outages of these plants to determine the annual outage requirement (number of days). Because the Company also used and expects to use spring and fall outages for these plants, I used the Company's planned fall outage for one, and a spring outage for the other. I used the same schedule for all four years.

Q. PLEASE PRESENT THE RESULTS OF THIS ANALYSIS.

A. The table below presents these results. The figures shown are compared to the Company's original schedule, the DPU/Company Alternative 1 schedule (developed by Mr. Dalton) and the Company Alternative 2 schedule. The figures demonstrate that the composite result for the four years, \$10.7 million is much closer to my proposed adjustment (\$11.0 million) than any other schedule proposed in this case. It confirms the reasonableness of my proposed schedule.

However, I would certainly not object to simply substituting results from this analysis for the outage adjustment I have already proposed. (Use of four schedules might be less convenient for compliance filing purposes, however.)

Table 3

Schedule	Change M\$	M mWh
2003-2004	-9.61	2.09
2004-2005	-26.13	1.57
2005-2006	-7.85	2.29
2006-2007	0.85	2.55
4 Yr. Average	-10.68	2.13
GRID Baseline	0.00	2.13
CCS 4.14	-11.00	
Company/DPU	-4.36	
Company Alt -2	-1.68	

Q. THE TOTAL NPC ADJUSTMENT FIGURES SHOW A WIDE COST VARIATION DURING THE FOUR-YEAR PERIOD. PLEASE EXPLAIN.

A. Outages are scheduled on a cyclical basis. The low cost year, (fall 2004 to summer 2005) was a period where relatively few planned outages were scheduled. The high cost period (2006-2007) coincides with a period where more than the average amount of outage energy was scheduled. This table actually provides a good reason for normalizing maintenance instead of using a single year. The results can vary substantially from one year to the next based on the actual outage schedule. This is why the Company uses a four-year average to develop the amount of planned outage energy to include in the test year.

Q. SHOULD THE COMMISSION VIEW THE COMPANY/DPU SCHEDULE AS A COMPROMISE BETWEEN YOUR PROPOSAL AND THE COMPANY'S OTHER PROPOSALS?

646 A. No. As shown above, the Company/DPU alternative produces a result that is
647 much more costly than the planned outage schedules the Company actually uses.
648 Indeed, it exceeds the cost of planned outage schedules for three of the past four
649 years. Further, as pointed out previously, this schedule has a number of problems,
650 and does not even remove all of the outage energy from the cold weather months.
651 The Commission should keep in mind that the goal of maintenance scheduling is
652 in fact to find the schedule that satisfies all scheduling constraints, but which
653 results in the lowest Net Power Costs. The four actual schedules used clearly
654 satisfy all scheduling constraints and produces much lower Net Power Costs. I
655 strongly recommend the Commission reject the Company and DPU proposals.

656 **CCS 4.22 (Heat Rate Modeling) CCS 4.23 (Minimum Loading Deration)**

657 **Q. DOES THE COMPANY AGREE WITH YOUR PROPOSED HEAT RATE**
658 **MODELING AND MINIMUM LOADING DERATION ADJUSTMENTS?**

659
660 A. No. Mr. Duval argues that the approach is wrong, because the Company has been
661 using its deration approach in the same manner for the past 25 years, and no
662 Commission has objected to it; that the exhibit supporting this technique is off
663 base and poorly explained; and that the unit minimum capacity is an invariant
664 quantity that should not be adjusted.

665 **Q. PLEASE COMMENT ON MR. DUVAL'S FIRST POINT.**

666
667 A. Since this is the first fully litigated Utah general rate case for net power cost
668 issues since 2001, there is no specific Commission policy on this issue for the past
669 several years. In 2001 and before, the Company used monthly energy cost
670 models (in 2001 the "spreadsheet model" and prior to that, PD-Mac). In such
671 models, minimum loadings are not modeled rigorously. Indeed, those models did

672 not even require the minimum loading point as an input. Rather a “displacement
673 limit” was used which set a floor on monthly generation. It is my recollection that
674 the Company objected to even using minimum loadings and actual plant
675 characteristics to develop these limits. The displacement limits were determined
676 judgmentally by the Company. As a result, this may be the first fully litigated
677 case in Utah in the past 25 years where the issue was even relevant.

678 Also, as pointed out in my direct testimony, GRID now shows many units
679 running at minimum loadings, far in excess of actual operations. Thus, this
680 problem is more important now and should be addressed.

681 **Q. IS MR. DUVAL CORRECT IN SAYING THAT THE COMPANY HAS**
682 **NEVER USED YOUR RECOMMENDED APPROACH IN ITS DERATION**
683 **MODELING?**

684 **A.** No. In fact, he’s not even correct as regards the GRID model. GRID models a
685 number of units for which the Company has partial ownership rights. The model
686 uses an input called “PacifiCorp ownership percentage”, which adjusts the heat
687 rate to reflect partial ownership. For example, the Company owns 10% of the
688 Colstrip units (76.5 mW out of 765 mW). The Company does not evaluate the
689 heat rate curve of Colstrip 3 at 76.5 mW (10% of full loading - which would be
690 less than the plant minimum) when it models the unit in GRID. Rather it adjusts
691 the heat rate curve to appropriately reflect its share of the plant ownership. My
692 proposal uses the same equation in making the deration adjustment. It simply
693 does so for a different reason than the Company does.

695 Further, while Mr. Duval dismisses the concept of adjusting minimum
696 capacities to reflect outages (as it does already for the maximum capacity) the

697 Company does exactly the same thing in preparing the minimum capacities for
698 partially owned units. All that my proposal does is to treat the loss of capacity
699 due to outages on the same basis as the Company already does for fractional
700 ownership.

701 **Q. EXPLAIN WHY THIS ADJUSTMENT IS NEEDED.**

702
703 A. Assume hypothetically, that Currant Creek had an outage rate of 50%. This
704 would mean the plant would only be available to run half the time. When it
705 would run, it would likely run fully loaded – at its most efficient heat rate.
706 However, based on the way GRID currently operates Currant Creek, it would be
707 derated by 50%, and therefore, would run at half of its full load (an amount less
708 than the minimum capacity of the plant). The Company's approach also would
709 evaluate the heat rate at the 50% loading point, which is clearly wrong. At only
710 half of full load, the unit would operate inefficiently. The Company's approach
711 assumes that it derates the unit capacity by 50%, but leaves out the heat rate and
712 minimum loading adjustments it makes in GRID for fractional ownership. It
713 would show Currant Creek running at a loading level less than its actual minimum
714 capacity, and at a high cost based on an inefficient heat rate.

715 In the recent Wyoming case, the Company's monthly outage rate data
716 showed a very high outage rate for Gadsby Unit 1 for one month of the test year.
717 This resulted in the unit being dispatched in GRID at only 570 kW, with a cost of
718 nearly \$1300/mWh. Exhibit CCS 4.2SR presents these results. While the
719 Company might argue such circumstances aren't present in this case, that is only

720 due to random chance. In order to avoid having to deal with such odd results
721 occurring in future cases, the Commission should accept my adjustment.

722 **Q. HOW DOES THIS APPROACH COMPARE TO INDUSTRY STANDARD**
723 **TECHNIQUES?**

724
725 A. As pointed out in Mr. Hayet's direct testimony which I have adopted, this
726 approach is well accepted by the community of production cost modeling experts.
727 Further, Portland General Electric ("PGE") uses an hourly deration model much
728 like GRID, which makes the very same type of adjustments to heat rates and
729 minimum loadings as I am proposing. Exhibit CCS 4.3SR provides copies of data
730 request responses from PGE's current general rate case which confirms that it
731 makes such adjustments to minimum loading and heat rates. I would note that the
732 Oregon Public Utility Commission has accepted the PGE model for some time.
733 Clearly, this is not an idea lacking in support throughout the industry.

734 Further, this methodology has been applied for quite some time in the
735 industry. Around 1980 as an employee of a major A&E firm, EBASCO Services,
736 I was responsible for development of a production cost model for use in
737 developing PURPA avoided cost reporting requirements for many EBASCO
738 clients. The model was used by many of the largest private and publicly owned
739 utilities at the time, including Con Edison, Texas Utilities, San Antonio City
740 Public Service Authority and Jacksonville Electric Authority to name just a few.
741 While the model used a Monte Carlo simulation technique, it also could be run
742 with the deration modeling option. I recently checked the code in the model, and
743 it used the same type of deration adjustments I am proposing here. Clearly, this is
744 not simply a novel new idea, but rather the right way to apply the deration model.

745 **Q. DISCUSS MR. DUVAL’S CRITICISM OF THE EXPLANATION YOU**
746 **PROVIDED FOR EXHIBIT CCS 4.16, WHICH SUPPORTED YOUR**
747 **DERATION ADJUSTMENT IN YOUR DIRECT TESTIMONY.**

748
749 A. Mr. Duval testifies on line 765 as follows:

750 When asked to explain the content of this exhibit in a data request from the
751 Company, Mr. Falkenberg responded by saying that “tracing through the
752 calculations shown on this exhibit will enable the Company to understand this
753 analysis.”
754

755 **Q. IS MR. DUVAL PROVIDING AN ACCURATE QUOTATION OF YOUR**
756 **ANSWER?**

757
758 A. No. My actual response to the data request is presented below:

759 **CCS Response to RMP Data Request 5.25**
760

761 See the answer to Question 5.9. Tracing through the calculations shown on this
762 exhibit will enable the Company to understand this analysis. Essentially, the
763 analysis shows that if the system had 2 units (Hunter and Gadsby) and each has
764 the outage rate shown, there are 4 possible states for the system. (Hunter Up,
765 Gadsby Up, Hunter Down Gadsby Up, Hunter Up Gadsby Down, and Both
766 Down). The model then calculates the production cost for each of the four states
767 and shows that unless the deration adjustments proposed by Mr. Falkenberg are
768 applied to the minimum loadings, and the heat rate equation, the deration model
769 (as used in GRID) will incorrectly state net power costs.

770
771 It is of some interest to note that the adjustment used for the heat rate curves is
772 essentially the same as the Company models for the “PacifiCorp Ownership
773 Percentage” variable as applied in GRID, and explain in the GRID algorithm
774 guide.
775

776 Finally, review of the MONET model used by Portland General Electric
777 Company shows that they also use the same approach in modeling of derated
778 capacity states as regards Mr. Falkenberg’s proposed heat rate and minimum
779 capacity state deration adjustments.
780

781 This answer provides more detail than Mr. Duval states above, and most
782 certainly did not stop at telling the Company to *trace through the calculations*. It
783 is also worth pointing out that the Company had this very exhibit and workpapers

784 in its possession since January 2008, when I filed it in the Wyoming case. I never
785 received a single question regarding the exhibit during that period of time. In
786 addition, the Company did not ask any follow up data requests regarding any
787 aspect of the exhibit, nor did it send any emails or make any telephone calls
788 seeking clarification after our data response was filed until after Mr. Duval filed
789 his rebuttal.

790 **Q. MR. DUVAL SAYS EXHIBIT CCS 4.16 IS UNREALISTIC BECAUSE IT**
791 **DOES NOT CONSIDER DERATIONS, ONLY FULL OUTAGES. WHAT**
792 **IS YOUR RESPONSE?**

793
794 A. Energy lost from full outages exceeds that due to partial outages by more than
795 60% for PacifiCorp generators. Full outages have a much more consequential
796 impact on system costs than do partial outages. Further, even in the case of
797 partial outages, the derated capacity used in GRID will not match the amount
798 modeled by the Company, as derations can result from a wide variety of plant
799 configurations. Therefore, cost will be misstated whether from full or partial
800 outages. My proposal is a logical way to deal with this problem.

801 **Q. DO YOU CONTINUE TO SUPPORT THIS ADJUSTMENT?**

802
803 A. Yes.

804 **CCS 4.17 (Monthly Outage Rate Modeling)**

805
806 **Q. DOES MR. DUVAL AGREE WITH YOUR PROPOSAL TO ELIMINATE**
807 **MONTHLY OUTAGE RATE MODELING?**

808
809 A. Yes, but only if the weekday, weekend differentiation of outage rates used in
810 GRID is eliminated as well. Mr. Duval offers virtually no support for this
811 proposal. He merely asserts that if a more general outage rate modeling is used,

812 then there is no justification for retention of the weekday, weekend forced outage
813 rate split.

814 **Q. DO YOU AGREE?**

815

816 A. Definitely not. There is no valid reason to model monthly outage rates, as Mr.
817 Hayet and I both pointed out in our direct testimony. Mr. Duval apparently agrees
818 because he did not even attempt to justify the monthly outage rate modeling
819 currently in use.

820 However, the weekend, weekday forced outage rate split is much
821 different. Unlike the monthly outage rate modeling, there are valid operational
822 reasons why outage rates are higher on weekends than on weekdays. There is a
823 definite pattern in weekend and weekday outage rates, rather than just random
824 variations that occur with monthly outages. Finally, weekend and weekday
825 outage rates can be computed based on a full 48 months of data rather than using
826 small samples of data limited to only four observations per unit for each of the 12
827 months.

828 **Q. EXPLAIN WHY OUTAGE RATES ARE HIGHER ON WEEKENDS**
829 **THAN ON WEEKDAYS.**

830

831 A. Certain types of outages, called maintenance outages can be deferred to avoid
832 taking units offline during high cost periods. The NERC definition of a
833 maintenance outage is an event that can be deferred until beyond the next
834 weekend, but not beyond the next planned outage. These types of outages have
835 flexible start dates, and the lost energy associated with them occurs more

frequently in the weekend and other off-peak periods.⁵ In order to minimize costs, utilities do schedule maintenance outages at lower cost periods such as during the weekend when possible. Maintenance outages and other deferrable events make up 15% of all energy lost by PacifiCorp generators. As a result, more than 90% of the Company's thermal resources have higher weekend than weekday outage rates. The weekend outage rates average 22% higher than the weekday outage rates for the Company resources. A comparison of weekend and weekday outage rates is shown on Exhibit No. CCS 4.4SR.

There are therefore two justifications for not discarding the weekend-weekday outage rate split. First, it reflects the actual cost minimizing practices of the Company. Second, there is a sound analytical basis for its use. This contrasts with the monthly outage rate approach which has no basis in actual practice and no analytic support. As a result, I recommend the Commission reject Mr. Duval's proposal.

Q. IS MODELING OF WEEKEND AND WEEKDAY OUTAGE RATES STANDARD INDUSTRY PRACTICE?

A. Yes, and it has been so for some time. Since the mid 1970s, PROMOD (a model in use by more than 100 utilities) had provisions for a weekend, or off-peak maintenance outage rate. Mr. Hayet still works with PROMOD on a regular basis and informs me that provision still is present in PROMOD and that it is commonly used. As he pointed out in his direct testimony, it is most certainly uncommon for utilities to use monthly or even seasonal outage rates. In the end,

⁵ Until 2005 the Company modeled all maintenance outages during the weekend period. Subsequently, it changed to the current method. While I believe the prior treatment is more

859 Mr. Duval's proposal lacks merit. The current methodology, using a different
860 weekend and weekday outage rate has been used by the Company in all of its
861 major rates cases since GRID was introduced. Until now, I am not aware of the
862 Company ever suggesting this should be discarded.

863 **CCS 4.19 (Ramping)**

864 **Q. DOES MR. DUVAL AGREE WITH YOUR PROPOSAL TO REVERSE**
865 **THE COMPANY'S RAMPING ADJUSTMENT?**

866
867 A. Mr. Duval continues to support the Company's inclusion of ramping in outage
868 rates, but does concede that for gas units, at least, the methodology may
869 *inadvertently cover a gas plant being held for reserve.* (Line 458). He also
870 contends that while the Washington Commission rejected the ramping adjustment,
871 it focused on the calculation method for outage rates not on the concept. (Lines
872 448-450.) Mr. Duval proposes a smaller ramping adjustment (\$1.7 million) than
873 the \$4 million I proposed.

874 **Q. DO YOU AGREE WITH HIS ALTERNATIVE PROPOSAL?**

875
876 A. No. First, while the analysis of ramping presented in Exhibit CCS 4.15 examined
877 only one of the Gadsby units, it should not be inferred that this problem applies
878 *only* to gas units. Many of the problems that resulted in an obvious overstatement
879 of ramping lost energy would apply to any type of unit. Many of the Company's
880 thermal units are required to supply reserves from time to time, and/or experience
881 deration events that would be counted as ramping in the Company's flawed
882 methodology. This can be seen by looking at other data available in this
883 proceeding.

appropriate, I will not press the issue in this case, but request the Commission keep an open mind

884 **Q. PLEASE ELABORATE.**

885 A. A more accurate approach to determining the ramping loss adjustment would be
886 to use the actual ramp rate for the unit. In the response to CCS 2.38 Confidential,
887 it is shown that the ramp rate for Gadsby 1 is X per minute. This would
888 imply the unit could reach 90% of full load in X minutes. For a single start, this
889 would result in total ramping losses of about XX XXX. Referring back to
890 Exhibit CCS 4.15, for the two starts that occurred in March 2007, this would
891 result in a total loss of generation no more than XX XXX as compared to 994
892 mWh in the Company's method. However, in both cases, some of the unit's
893 capacity was assigned to reserves, so the actual loss would be less, as the units
894 would not have needed to be ramped up to full capacity. Further, there is no
895 reason to assume the unit would have been dispatched to full load. Because it
896 takes XXXXXXXXXX for the unit to ramp up to full load, and the subsequent
897 hours were dispatched to less than full loading, the Company's methodology most
898 certainly overstates energy lost due to ramping.

899 **Q. CAN YOU DEMONSTRATE THAT THE COMPANY'S RAMPING**
900 **ADJUSTMENT IS OVERSTATED FOR ALL PACIFICORP UNITS**
901 **BASED ON THE ACTUAL RAMP RATES REPORTED IN CCS 2.38?**

902
903 A. Yes. Exhibit No CCS 4.5SR shows a computation of the total amount of energy
904 lost due to ramping based on the number of starts in the four year period and
905 actual unit ramp rates. It shows that at the very most, the lost energy due to
906 ramping amounts to 23% of the amount the Company includes in GRID.

907 Even the 23% figure overstates ramping losses because it ignores the fact
908 that units often run below full load due to load conditions, reserve allocations, or
909 due to partial outages. Further, as shown in Exhibit CCS 4.15, the Company
910 assumes ramping losses can occur many hours after a unit is started and running
911 near full load, and the Company assumes that when a unit starts to shut down,
912 even more energy is lost to ramping.

913 In the end, there is little basis for the outage rate adjustment for ramping
914 proposed by the Company. The Commission could reject the Company's entire
915 ramping proposal. However, purely as a compromise for this case, I have
916 recomputed my ramping adjustment allowing the maximum possible ramping
917 energy based on the actual thermal unit ramp rates. Exhibit CCS 4.5SR shows the
918 maximum ramping energy for each plant. I have reflected this additional ramping
919 in CCS Adjustment 4.19SR.

920 My revised ramping adjustment also makes a minor correction to the
921 computation of outage rates. In my computation of the annual outage rates I
922 simply averaged the twelve monthly weekend and weekday outage rates.
923 However, this assumes all months have the same number of days, and doesn't
924 give the most accurate weighting. A more accurate calculation would compute
925 the annual weekend and weekday rates based on annual ratio of lost to scheduled
926 energy. This is the way in which the Company computed its annual average
927 outage rate in preparing its rebuttal. I included this adjustment in my computation
928 of the revised outage rates used in CCS 4.19SR. Overall, my revised outage rate

929 calculation methodology results in an increase to NPC (as compared to my direct
930 testimony) of approximately \$1.5 million total Company.

931 **Other Updates, Corrections and New Costs**

932 **Q. DO YOU HAVE ANY CORRECTIONS YOU WISH TO MAKE AT THIS**
933 **TIME?**

934
935 A. Yes. I discovered that there was an error in Table 1 in my direct testimony in that
936 it did not contain the correct figure for Call Option Adjustment, CCS 4.5. The
937 figure shown simply did not match the figure supported in my exhibit, a purely
938 typographical error. Correcting it results in an increase to total Company NPC of
939 \$1.1 million. There was also a minor (\$400) error in Exhibit CCS 4.5, which I
940 also corrected.

941 **Q. HAS MR. DUVAL ACCEPTED ANY OTHER ADJUSTMENTS AS**
942 **CORRECTIONS TO THE FILING?**

943
944 A. Mr. Duval accepts the corrections proposed for the Currant Creek outage rates
945 (CCS 4.21), SMUD Leap Year Adjustment (CCS 4.8) and Self Supply Non-
946 owned Reserves (CCS 4.26). As discussed above, Mr. Duval also acknowledges
947 the dispatch logic in GRID is wrong, and believes a net adjustment in excess of \$9
948 million should be made. However, he proposes to make this correction on a
949 conditional basis only.

950 **Q. DID MR. DUVAL FULLY IMPLEMENT THE FIRST THREE**
951 **ADJUSTMENTS?**

952
953 A. No. The Currant Creek outage rate adjustment contained two parts – a forced
954 outage rate adjustment and a planned outage rate adjustment. He only accepted
955 the former adjustment. The latter adjustment reduced the Currant Creek planned
956 outage duration for the test year from 9 to 8 days. Though this is an

957 inconsequential adjustment under my proposed outage schedule, it could be more
958 significant under the Company's proposed outage schedule. It should be accepted
959 in either case.

960 Also, it appears that Mr. Duval did not accept all of the Self-Supply non-
961 owned reserves adjustment. This again had two parts, both an eastern and a
962 western control area component. It appears that Mr. Duval accepted only the
963 eastern control area component of the adjustment. In recent discovery in the
964 Washington case, the Company acknowledged that it overstated reserve
965 requirements for the western control area as well. (See Exhibit No. CCS 4.6SR.
966 Note that the Washington case used the same GRID inputs for this item as in this
967 case.) However, at this point, it appears that I also overstated the western control
968 area portion of the adjustment because I removed more than these two contracts.
969 Removing only the two contracts that the Company agrees self supply reserves
970 results in an additional increase to Mr. Duval's computation of the CCS 4.26
971 adjustment by about \$200 thousand and reduces my proposed adjustment. My
972 corrected adjustment for this issue is shown on Table 1 Surrebuttal.

973 Finally, as discussed above, Mr. Duval did not implement the GRID logic
974 correction in his recommended NPC result of \$1,044 million.

975 **Q. DID MR. DUVAL PROPOSE ANY OTHER CORRECTIONS TO THE**
976 **FILING?**

977
978 A. Yes. Mr. Duval proposes to include electricity swaps and indexed gas
979 transactions amounting to \$3.2 million. These were left out by mistake according
980 to Mr. Duval.

981 **Q. DO YOU AGREE WITH THE INCLUSION OF THESE KINDS OF**
982 **COSTS?**

983
984 A. No. It includes new kinds of costs, making it more of an update than a correction.
985 It troubles me that the Company has first informed parties of this substantial error
986 at this late date and in such an indirect manner. I am also concerned that this
987 could be considered as establishing precedent. By introducing new kinds of costs
988 at this time, the Company effectively limits the parties' opportunity to inquire as
989 to the prudence of the costs and the most appropriate ratemaking treatment.

990 **Q. ARE THERE OTHER ASPECTS TO THIS PROBLEM?**

991 A. In its decision concerning the test year, the Commission invited the Company to
992 update its filing when it prepared the new test year. The Company made no
993 corrections or updates to GRID at that time, though it did make at least one other
994 correction at that time.

995 **Q. HAS MR. DUVAL ACCEPTED ANY OTHER ADJUSTMENTS?**

996
997 A. Yes. Mr. Duval has conditionally accepted the following adjustments: CCS 4.6
998 (Hermiston Losses); CCS 4.10 (Biomass Non Gen); CCS 4.11, DPU 6.1 and UAE
999 1.6 (Sunnyside QF); CCS 4.12 (Schwendiman Contract Deferral); CCS 4.27
1000 (Goodnoe Transmission); CCS 4.28 (Borah Brady Transmission); CCS 4.29
1001 (Transmission Cost Escalation) and DPU 6.3 (Tesoro and Kennecott PPAs).
1002 While I am glad that the Company has recognized the validity of these
1003 adjustments, I disagree with his characterization of these as "updates" or "new
1004 information." These adjustments do not rest on new information at all.

1005 The Hermiston Loss adjustment was based on a letter the Company
1006 received in early 2005. The Company instituted its Hermiston loss adjustment in

1007 GRID around that time. This clearly does not represent “new information”, but
1008 rather proper application of information long available to the Company.

1009 The Sunnyside QF contract negotiation was completed in 2007. The
1010 Company actually used an estimated price revision for its actual power cost
1011 reports in 2007 as well. Had the Company estimated the final impact of the new
1012 contract in its direct case, then updated it with final numbers it would be fair to
1013 characterize this as an update. Instead, it amounts to a correction.

1014 The Borah Brady Transmission Pro-Forma, Goodnoe Transmission Pro-
1015 Forma and Transmission Cost escalation adjustments are not based on new
1016 information either. While the Borah Brady adjustment was based on recent data,
1017 it was necessary to correct information used in the filing for which the Company
1018 could not provide any support. The Company could have used supportable
1019 information in the first place. My Transmission Cost escalation adjustment was
1020 based on data available to the Company as of November 2007, prior to the filing.
1021 The corrected Goodnoe cost data was filed by the Company in Washington in
1022 February, 2007, well in advance of the time it filed its 2008 test year.

1023 Likewise, the Biomass non-generation agreement adjustment was
1024 premised on the fact that the Company had entered into such agreements for the
1025 previous three years. This was well known to the Company when its case was
1026 filed. Finally, the Schwendiman contract adjustment was based on the Third
1027 Amended contract dated October 2007, again, in advance of the filing date.

1028 **Q. WHY IS IT IMPORTANT TO CHARACTERIZE THESE ADJUSTMENTS**
1029 **AS CORRECTIONS RATHER THAN UPDATES?**
1030

1031 A. Mr. Duval has attempted to blur the line between our legitimate “corrections” and
1032 his illegitimate “update.” If the Commission were to decide against allowing
1033 updates (such as Mr. Duval’s proposed forward curve adjustment) it should not
1034 eliminate these legitimate corrections at the same time.

1035 **Q. IS THERE ANY REASON THE COMMISSION SHOULD BE CAUTIOUS**
1036 **OF UPDATES LATE IN A CASE?**

1037
1038 A. Certainly. Mr. Duval has already expressed the Company’s sentiment that Utah
1039 regulation has systematically resulted in the Company under-recovering its costs.
1040 Presentation of an 11th hour “update” of this sort raises the concern that updates
1041 for cost reducing items were overlooked.

1042 **Q. DO YOU OPPOSE MR. DUVAL’S FORWARD CURVE UPDATE?**

1043
1044 A. Yes. In the case at hand, it is clear that the Company ignored inputs that would
1045 reduce its cost. Mr. Duval proposes to update only the forward cost curve, but did
1046 not reflect changes to hydro shaping that accompany the new forward curves.
1047 The Company refused to provide the revised GRID inputs resulting from
1048 reshaping when we specifically asked for them in a data request. The Company
1049 did make such hydro shaping adjustments in other cases when it revised the
1050 forward price curve. I estimate this item alone would result in a reduction to NPC
1051 of \$500 thousand on a total Company basis based on results in recent cases.

1052 **Q. MR. DUVAL SUGGESTS YOU WOULD NOT OBJECT TO THE**
1053 **FORWARD CURVE UPDATE BECAUSE IT IS USED IN OREGON AND**
1054 **IS A MINOR CHANGE. PLEASE COMMENT.**

1055
1056 A. In Oregon, specific types of updates are allowed on a specific schedule. Updates
1057 in Oregon are not optional at the Company’s discretion, as Mr. Duval seems to
1058 prefer in this case. Further, in prior Oregon cases, when updates were prepared

1059 the Company provided a separate GRID run for each new contract or major input
1060 category so that parties could evaluate the changes. In this case, the Company has
1061 not even provided the actual value of its forward curve adjustment, but instead
1062 coupled it with other adjustments. Further, the Oregon process allows for parties
1063 to challenge adjustments made by requesting a new procedural schedule. This
1064 was done in a PGE case in late 2004, when a call option contract was first
1065 introduced.

1066 The Commission already gave the Company the opportunity to update its
1067 case when it produced the 2008 test year. The Company should not be allowed
1068 “another bite at the apple” simply because its NPC study has so many flaws and is
1069 demonstrably overstated. Mr. Duval’s proposed update is little more than a
1070 request for a “do-over.”

1071 Finally, as regards the suggestion that the forward price curve change is a
1072 minor matter, this is most certainly not the case. I estimate that the forward curve
1073 adjustment amounts to more than a \$10 million increase to NPC. However, the
1074 actual components of this change are far more significant. Mr. Duval changes the
1075 gas swaps line in GRID by \$66 million but this is more than offset by other
1076 changes in gas prices, electric prices and certain contract prices of more than \$76
1077 million. Clearly, the forward curve update is a major change in the model.

1078 **CCS 4.5 (Call Options) and CCS 4.13 (STF Arbitrage and Trading)**
1079

1080 **Q. MR. DUVAL OPPOSES YOUR CALL OPTION ADJUSTMENT ON THE**
1081 **BASIS THAT IT IS UNIQUE TO THE OREGON REGULATORY MODEL**
1082 **AND NOT APPLICABLE TO UTAH. PLEASE COMMENT.**
1083

1084 A. The issue of call options is one I have raised in earlier settled cases and there is no
1085 Commission precedent on this matter in Utah. If nothing else, it would help for
1086 the Commission to rule on this matter. In my direct testimony, I already
1087 addressed the argument that the Oregon procedure (proposed by the Company)
1088 should not be applicable in Utah, so I won't repeat it here.

1089 **Q. MR. DUVAL EXPRESSES CONFUSION SURROUNDING THE CALL**
1090 **OPTION ADJUSTMENT OF \$3.59 MILLION. HE ALSO SUGGESTS**
1091 **THAT THE COMPANY COULD NOT UNDERSTAND YOUR ANALYSIS**
1092 **OR WORKPAPERS. PLEASE COMMENT.**

1093
1094 A. I accept responsibility for the mistake related to the incorrect value for the call
1095 option adjustment appearing on Table 1 as well as any confusion it created.
1096 However, the figure \$3.59 million was supported in Confidential Exhibit CCS4.7
1097 and detailed workpapers were provided to the Company.

1098 As I pointed out earlier, this concept is one that the Company has already
1099 proposed in Oregon so they should have had little trouble understanding the
1100 matter. To ensure, however, that the Commission understands this adjustment, I
1101 present Confidential Exhibit CCS 4.7SR which provides a calculation of the
1102 disallowances related to the NEBO contract. I believe review of this work will
1103 establish that the concept is not difficult to understand, and in fact, is quite similar
1104 to the approach used to determine uneconomic generation on a daily basis for
1105 West Valley. I already presented that analysis as Exhibit CCS 4.5 in my direct
1106 testimony.

1107 **Q. MR. DUVAL AGREES THAT CALL OPTION CONTRACTS SHOULD**
1108 **NOT BE DISPATCHED UNECONOMICALLY IN GRID. HOWEVER,**
1109 **HE SUGGESTS THAT THE PROBLEM IS INCONSEQUENTIAL.**
1110 **PLEASE COMMENT.**
1111

1112 A. It appears that Mr. Duval has not analyzed this problem on a daily or even
1113 monthly basis. Based on a run using his new forward price curve (Line 4 on
1114 Alternative 2 of GND-1R-RR) without NEBO, there is \$635 thousand in
1115 uneconomic generation costs for that contract in March 2008 alone. This is nearly
1116 70% of the \$922 thousand adjustment I estimated in my direct testimony. Mr.
1117 Duval has not cured the uneconomic generation problem by changing the forward
1118 price curve. As a result, I continue to support this adjustment irrespective of any
1119 change to the forward price curve.⁶

1120 **Q. DO YOU AGREE WITH MR. DUVAL'S CRITICISM OF THE SHORT**
1121 **TERM FIRM ARBITRAGE AND TRADING PROFITS ISSUE?**
1122

1123 A. His arguments on this matter parallel those of the call option issue. In this case,
1124 however, I agree to withdraw the adjustment because it quite specific to the
1125 Oregon TAM process and the Company has never agreed to its use. Oregon uses
1126 a fully projected test year (the current Oregon NPC case uses a December 31,
1127 2009 test year.) This allows less opportunity to capture the actual benefits of the
1128 STF transactions in the test year, as most arbitrage and trading opportunities seem
1129 to arise closer in time to actual trade dates. Use of an earlier test year tends to
1130 undermine the Oregon justification for this adjustment.

1131

1132 **CCS 4.7 and CCS 4.9 (SMUD)**

1133 **Q. MR. DUVAL TESTIFIES THAT NO CHANGE IN THE SMUD IMPUTED**
1134 **PRICE SHOULD BE MADE. PLEASE COMMENT.**
1135

1136 A. Mr. Hayet supports an imputed price of \$43.8/mWh for SMUD. As Mr. Hayet
1137 pointed out, the cost of serving SMUD is \$76/mWh, far less than his

⁶ Should the new forward curve be adopted, the adjustment should be recomputed.

1138 recommended contract price. I believe this demonstrates the reasonableness of
1139 the Committees' SMUD adjustments and we continue to support them for the
1140 reasons provided in our direct testimony.

1141 **Q. PLEASE COMMENT ON MR. DUVAL'S CONTENTION THAT IF SMUD**
1142 **IS REPRICED, THEN SO SHOULD THE MID-C CONTRACT.**

1143
1144 A. This is a specious argument. The Commission has already recognized that the
1145 history of the SMUD contract differs from that of other contracts, such as Mid C.
1146 SMUD is the only contract for which the Commission has a long history of price
1147 imputation because the reasonableness of this contract is in question. The
1148 Company did not get to keep a \$98 million up front payment for any other below
1149 market contract it now has in place. The Commission should reject this argument.

1150 **Q. WHY DOES MR. DUVAL OPPOSE THE SMUD CONTRACT**
1151 **NORMALIZATION ADJUSTMENT?**

1152
1153 A. Mr. Duval asserts that it is not a proper normalization, but provides no
1154 explanation or support. He also contends this adjustment is "one-sided" and
1155 "selective." I disagree on both points.

1156 First, the concept of normalization is to use actual data where applicable,
1157 but to smooth out year to year variations. I did this with SMUD, using a four-year
1158 average monthly energy distribution. The Company uses four-year averages for
1159 many inputs to GRID. There is nothing improper about this normalization
1160 technique.

1161 Second, Mr. Duval suggests it is one sided to apply this adjustment only to
1162 SMUD, and that I should have looked at other contracts. The Company has more
1163 than 70 contract line items in GRID. Some of these line items represent a

1164 combination of many smaller contracts. It is an unreasonable standard to suggest
1165 that one contract cannot be corrected, unless all contracts are corrected. The
1166 Company did not insist upon this standard when it agreed to the adjustments to
1167 the various other contracts proposed by Mr. Dalton, or Mr. Hayet, or even the
1168 SMUD Leap Year adjustment.

1169 **Q. MR. DUVAL TESTIFIES YOU ARE PROPOSING TO “DE-OPTIMIZE”**
1170 **SMUD WHILE SEEKING TO OPTIMIZE SYSTEM DISPATCH. IS THIS**
1171 **A REASONABLE CRITICISM?**

1172
1173 **A.** No. The Company controls the operation of its system and attempts to minimize
1174 cost. SMUD does the same for its system. Mr. Duval has already acknowledged
1175 that GRID is in error in the way it seeks to utilize certain resources but that fact
1176 has no relationship to SMUD. The energy demanded by SMUD is not controlled
1177 by the Company, but rather by the counterparty. Mr. Duval seeks to model the
1178 “worst case scenario” in the way that the contract *could* be used by the
1179 counterparty. As I pointed out in my direct, one must assume the SMUD contract
1180 is optimized by the counterparty subject to the constraints they face. However,
1181 their circumstances differ from those of the Company. The Company’s modeling
1182 completely ignores whatever real world factors drive SMUD to make different
1183 choices concerning how the contract is used. SMUD’s objective is to minimize
1184 its own costs, not to inflict the maximum cost on PacifiCorp. Mr. Duval simply
1185 refuses to acknowledge this fact.

1186 Finally, the Commission should recognize that when the SMUD contract
1187 price imputation was last decided, the Company did not model SMUD as a call
1188 option sale. Rather the Company used an energy distribution that showed sales

1189 taking place in both low and high cost months. The Commission has never ruled
1190 on whether SMUD should be modeled as a call option sale or not, but its last real
1191 decision used a much different approach. This point (made in my direct
1192 testimony and illustrated in Table 2) has not been addressed by Mr. Duval.

1193 **CCS 4.15 (Hydro Modeling) and CCS 4.16 (Hydro Reserve Input Parameter)**
1194

1195 **Q. PLEASE COMMENT ON MR. DUVAL'S TESTIMONY CONCERNING**
1196 **THE CCS 4.15 ADJUSTMENT.**

1197
1198 A. What is clear from his testimony is that Mr. Duval opposes any hydro adjustment.
1199 Unfortunately, Mr. Duval's testimony is contradictory and inaccurate. It would
1200 appear that Mr. Duval did not understand my proposal. For example, Mr. Duval
1201 testifies at lines 636-641 as follows:

1202 Mr. Falkenberg alleges that the Company's VISTA model for modeling
1203 normalized hydro generation overstates the likelihood of extreme hydro
1204 conditions. He recommends that the Commission eliminate this alleged bias by
1205 changing the weights for the Wet, Median and Dry cases to those he developed
1206 based upon historical data. This adjustment lowers modeled NPC \$3.5 million on
1207 a total company basis.
1208

1209 While the above characterization of my testimony is accurate, Mr. Duval
1210 states on line 655 "Mr. Falkenberg argues for exclusive use of the median, or 50
1211 percent exceedance level." This is not only inaccurate it also contradicts the first
1212 passage quoted above. My proposal was to use proper weights applied to the
1213 Wet, Median and Dry scenarios.⁷

1214 **Q. MR. DUVAL DISPUTES YOUR CONTENTION THAT THE COMPANY'S**
1215 **WET AND DRY CASES OVERSTATE THE LIKELIHOOD OF**
1216 **EXTREME EVENTS. PLEASE COMMENT.**
1217

⁷ I did suggest the use of the Median case, but only as the minimum necessary correction to the power cost study.

1218 A. Mr. Duval provides little support for this assertion and never addressed the
1219 analysis I performed proving this point. My direct testimony showed that the Wet
1220 and Dry cases that Mr. Duval assumes represent the 25, and 75 percent cases,
1221 really represent the 1 percent and 98 percent cases. (See Exhibit CCS 4.11).

1222 **Q. ON WHAT BASIS DOES MR. DUVAL DISPUTE THIS ADJUSTMENT?**

1223
1224 A. Mr. Duval makes three arguments. He asserts, without any support, that the
1225 Company's method "fairly approximates" the Wet, Dry and Normal cases (line
1226 679); that the Oregon Commission rejected a much different proposal I made last
1227 year; that there is "some correlation" between river systems (line 665, again with
1228 no support); and that it probably doesn't matter anyway (line 681, again without
1229 support).

1230 **Q. HOW DO YOU RESPOND TO THESE ASSERTIONS?**

1231
1232 A. It is rather difficult to respond meaningfully to unsupported assertions or to
1233 irrelevant issues such as the recent Oregon order which addressed a different
1234 adjustment than I am proposing in this case. His point that "some correlation"
1235 exists between river systems can be tested, however. The table below shows the
1236 actual correlation for annual energy generation from 1964 to 2003 for the five
1237 major river systems from which the Company obtains hydro energy. The analysis
1238 shows moderately strong correlation between the Umpqua and Klamath rivers
1239 ($p=.81$), but only moderate to very weak correlation for the rest. While Mr. Duval
1240 might be satisfied that this demonstrates "some correlation" exists, the
1241 Company's method assumes *nothing less than perfect correlation*. This is why the

1242 Company's method so substantially overstates the severity of the wet and dry
 1243 cases, as shown in CCS 4.11.

1244 **Table 4 Hydro Correlation – Major River Systems: 1964-2003**

1245		Umpqua	Klamath	Lewis	Mid C	Bear
1246	Umpqua	1.00	0.81	0.47	0.34	0.63
	Klamath		1.00	0.63	0.32	0.50
1247	Lewis			1.00	0.13	0.11
1248	Mid C				1.00	0.39
1249	Bear					1.00

1250

1251

1252 **Q. DO YOU CONTINUE TO SUPPORT YOUR ORIGINAL ADJUSTMENT?**

1253

1254 A. While I continue to believe this is a reasonable adjustment, I would be satisfied if
 1255 the Commission required the Company to file a conventional forty water year
 1256 modeling study as one of the MDRs in its next general rate case, similar to that
 1257 required in Washington. The availability of a forty water year study applicable to
 1258 the test year would enable the Commission to determine whether the Company's
 1259 approach is biased or not. This is a proven technique and would resolve this
 1260 entire controversy. The Company is already required to produce this data for one
 1261 other jurisdiction.

1262 **Q. DO YOU ACCEPT MR. DUVAL'S ARGUMENTS CONCERNING THE**
 1263 **HYDRO RESERVE INPUT PARAMETER?**

1264

1265 A. Mr. Duval provides no analytical support for the assertions he makes concerning
 1266 this input. However, as I pointed out in my direct testimony, this issue was not
 1267 included in the Committee's total NPC adjustment. I believe the issue warrants
 1268 further study before any adjustment is made. Mr. Duval has certainly provided

1269 nothing to suggest the Commission should not investigate this matter in future
1270 cases.

1271 **CCS 4.20 (Duct Firing Reserve Capability)**

1272 **Q. DO YOU ACCEPT MR. DUVAL'S ARGUMENTS CONCERNING THE**
1273 **MODELING OF DUCT FIRING?**

1274
1275 A. Mr. Duval is incorrect in his assertion that the heat rate curve used in GRID
1276 cannot model the jump to a higher heat rate curve when duct firing is started. In
1277 fact, the heat rate equation used in GRID is based on operation of the plant in both
1278 its conventional and duct firing mode of operation. (This is very clear from the
1279 Confidential Response to CCS 7.5.) However, as I pointed out in my direct
1280 testimony, this issue was not included in the Committee's total NPC adjustment.
1281 I continue to recommend the Commission require the Company to address this
1282 problem in its next general rate case.

1283 **CCS 4.24 (Station Service)**

1284
1285 **Q. DOES MR. DUVAL OPPOSE THIS ADJUSTMENT?**

1286 A. Yes. He asserts that "*Unless a separate load adjustment is made as proposed by*
1287 *the Company, the costs of that station service will not be recovered by the*
1288 *Company and there will not be a proper match between costs and benefits*" (lines
1289 805-808). He provides no logical support for the assertion that a load adjustment,
1290 rather than a heat rate adjustment is required. This is the same treatment applied
1291 to more than 99% of station service requirements in the development of GRID
1292 heat rate inputs. His main argument for treating this very small component of
1293 station service differently from the rest is that "*Load is equal to net generation*
1294 *plus interchange. Net generation only captures station service when the units are*

1295 *running, thereby excluding station service when the units are not running.”* (lines
1296 801-803.) In other words, it is not because the nature of the station service load
1297 differs when units are not running just that it has not been counted properly in the
1298 net load calculation. Therefore there is no reason to treat this component of
1299 station service any different from the rest – it should be reflected as an increase to
1300 generator heat rates, rather than as an incremental load.

1301 **Q. WHAT IS YOUR RECOMMENDATION?**

1302

1303 A. This issue comes down to how station non-running service costs should be
1304 computed in GRID. I don’t find Mr. Duval’s arguments persuasive, but now
1305 believe it may be worthwhile to try to reconcile the differences between the two
1306 approaches before making a change to the current modeling.

1307 **CCS 4.18 (Bridger Error Outages)**

1308 **Q. DOES THE COMPANY OPPOSE THIS ADJUSTMENT?**

1309

1310 A. Yes. The Company presents the testimony of Mr. Mark Mansfield, Vice
1311 President of Thermal Operations Support. Mr. Mansfield makes a number of
1312 arguments, but never addressed the reasonableness of the specific outages for
1313 which I recommend disallowances (identified in Confidential Exhibit CCS 4.14.)
1314 As a result, the prudence of these specific outages has not been justified by the
1315 Company. As prudence was the foundation of my proposed adjustment, I will
1316 only provide a limited response to Mr. Mansfield’s otherwise unresponsive
1317 arguments.

1318 **Q. MR. MANSFIELD MAKES MUCH OF THE FACT THAT THE**
1319 **CAPACITY FACTOR FOR PACIFICORP PLANTS EXCEED THE NERC**
1320 **AVERAGES. PLEASE COMMENT.**

1321

1322 A. This is an irrelevant comparison. PacifiCorp has load that exceeds coal-fired
1323 generation most hours of the year, and market prices in the region exceed coal
1324 dispatch costs throughout the year. This is not always the case in other regions of
1325 the country. In many parts of the country, coal is at the margin many hours of the
1326 year. As a result, coal capacity factors for PacifiCorp exceed those of other
1327 regions. This has little to do with anything PacifiCorp is responsible for. It
1328 would be like saying my car is more reliable than Mr. Hayet's because I drive 20
1329 mile a day to work, while he only drives 10.

1330 **Q. PLEASE COMMENT ON MR. MANSFIELD'S TESTIMONY**
1331 **CONCERNING THE EQUIVALENT AVAILABILITY FACTOR AND**
1332 **THE PLANNED OUTAGE FACTOR.**
1333

1334 A. Given the demonstrated increase in unplanned outages, Mr. Mansfield seems to
1335 be admitting that the Company has reduced planned outages at the expense of
1336 unplanned outages. This is a questionable strategy because planned outages can
1337 be scheduled at low cost times, while unplanned outages can happen at any time.
1338 An unplanned outage can cost many times more than a planned one. Should the
1339 Company experience system wide outages during summer or winter peaks in the
1340 months ahead, this strategy may be to blame.

1341 Finally, Mr. Mansfield certainly lends credence to the testimony of IBEW
1342 witness, Mr. Gary Cox, who believes the Company has undertaken this
1343 questionable strategy as a cost-cutting measure. I question the prudence of Mr.
1344 Mansfield's strategy and recommend the Commission do so as well.

1345 **Q. MR. MANSFIELD ARGUES IT IS ONE-SIDED TO PENALIZE THE**
1346 **COMPANY FOR THE POOR PERFORMANCE OF BRIDGER, WHILE**
1347 **IGNORING OTHER PLANTS. PLEASE COMMENT.**
1348

1349 A. The prudence standard applies to all plants not just Bridger. One does not get a
1350 reward for being prudent, but there has always been a penalty for imprudence. I
1351 presented direct evidence from the Company's own RCA reports that call into
1352 question the prudence of specific outages at Bridger. The Company has not
1353 justified the prudence of any of these events.

1354 **Q. WHAT IS YOUR RECOMMENDATION?**

1355
1356 A. Based on the testimony of Mr. Cox and Mr. Mansfield, I believe that by far the
1357 most significant issue in this case is the question of the Company's overall
1358 maintenance practices and strategy. I seriously question whether reducing
1359 planned outages is a reasonable trade-off for increased forced outages.

1360 I would have liked to have analyzed the costs of reduced planned outages
1361 versus increase forced outages in this case. However, time is too short for that
1362 now. Consequently, I believe this issue should be investigated much more fully
1363 before proceeding with an outage rate adjustment. Rather, I recommend that the
1364 Company be required to justify the economics of its scheduled maintenance
1365 strategy and practices in its next general rate case.

1366 **CCS 4.25 (Wind Integration Charges)**

1367 **Q. MR. TALLMAN DISPUTES YOUR WIND INTEGRATION**
1368 **ADJUSTMENT. PLEASE COMMENT.**

1369
1370 A. Mr. Tallman contends it was not proper to apply the IRP Appendix J methodology
1371 to the test year level of installed wind capacity; that it was incorrect to use GRID
1372 to compute the cost of wind integration; that the Company left some of the wind
1373 resources out of its calculation; and that BPA has now instituted a new wind
1374 integration charge.

1375 His first point is that the wind integration charge developed in the IRP was
1376 not intended to be parsed out into individual components of the wind portfolio.
1377 This is irrelevant, however, because I used a wind reserve requirement consistent
1378 with the chart on page 192 of Appendix J to the IRP that relates installed capacity
1379 to the incremental reserve requirement. It is now an accepted fact that as installed
1380 wind capacity increases, the average cost of wind integration increases as well.
1381 Mr. Tallman is suggesting that if the Company stopped adding new wind
1382 resources, the reserve requirement for the current 1200 mW would be the same as
1383 for the originally planned 2000 mW. Contrary to Mr. Tallman's testimony, this
1384 does not mean I would claim later wind units should be assessed higher
1385 integration charges than current ones. Rather, as more wind resources are added,
1386 a new charge should be computed and applied to all wind resources.

1387 I do agree, however, that GRID may not provide the best means of
1388 assessing the wind integration cost. I also accept his proposal to correct the error
1389 in the Company's filing related to the excluded wind resources. Based on his
1390 figure of 1200 mW of installed wind capacity, the Chart on page 192 of Appendix
1391 J, results in added reserve requirements of 10 mW. Applying this to the equation
1392 provided on page 193, of Appendix J, results in a wind integration charge of
1393 \$.22/mWh. Adding in the excluded wind energy, results in a total wind
1394 integration cost of \$1,242,997 less than proposed by the Company. I recommend
1395 this wind integration adjustment be applied to the 2008 test year.

1396 **Q. PLEASE COMMENT ON HIS PROPOSAL TO UPDATE THE TEST**
1397 **YEAR BASED ON THE NEW BPA CHARGES.**
1398

1399 A. It is my understanding that this rate change has not yet been approved, and it
1400 won't go into effect until October, 2008 if approved.

1401 **Corrections to Rebuttal Testimony**

1402 **Q. DO YOU HAVE ANY CORRECTIONS TO THE REBUTTAL**
1403 **TESTIMONY YOU FILED ON MAY 9, 2008?**

1404
1405 A. Yes. On page 4, line 71, I stated that the Company started no coal plant planned
1406 outages in January from 1990 to present. I have reexamined the data and found
1407 that one outage was started in January in 1993. I also found some minor revisions
1408 to Exhibit CCS 4.1R were necessary. I provide those in Exhibit CCS
1409 4.1R Supplemental. In the exhibit I also show the start dates for the Company's
1410 Alternative 2 planned outage schedule.

1411 **Q. DOES THIS CONCLUDE YOUR TESTIMONY?**

1412
1413 A. Yes.